TRUE energy inc.

2003 Annual Report to Shareholders

True Energy Inc. is a public junior oil and gas exploration company based in Calgary, Alberta, Canada, formed on August 31, 2000 with the amalgamation of Sundance Resources Inc. and two private Alberta companies.

True's corporate philosophy is to grow through exploration and development drilling complemented by both corporate and asset acquisitions.

Exploration plays are primarily internally generated medium-risk prospects, with up to one higher-risk "corporate accelerator" targeted to be drilled each quarter.

True Energy Inc.'s common shares are listed on the Toronto Stock Exchange under the trading symbol TUI. At the end of the year 2003, True's market capitalization was just under $90 million, with a closing trading price of $1.66 per share and 54 million shares issued and outstanding.

ANNUAL AND SPECIAL MEETING

True Energy Inc. invites shareholders and interested parties to attend its Annual and Special Meeting to be held in the Viking Room at the Calgary Petroleum Club, 319 - 5 Avenue SW, Calgary, Alberta on Thursday, May 20, 2004 at 3:30 p.m. (Calgary time).

Shareholders not attending the meeting are encouraged to complete the form of proxy and forward it at their earliest convenience.

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Financial and Operating Highlights

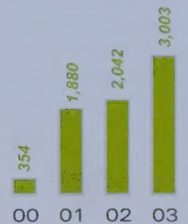
For the years ended December 31,

	2003	**2002**
FINANCIAL *($, except shares)*		
Revenue	**37,560,432**	18,974,327
Funds flow from operations [1]	**15,807,526**	6,088,361
Per share - basic	**0.33**	0.17
Per share - diluted	**0.32**	0.17
Cash flow from operations	**15,807,526**	5,911,661
Per share - basic	**0.33**	0.16
Per share - diluted	**0.32**	0.16
Net earnings	**4,328,751**	221,663
Per share - basic	**0.09**	0.01
Per share - diluted	**0.09**	0.01
Capital expenditures, net	**20,039,875**	18,802,290
Debt, net of working capital	**14,460,532**	19,892,545
Total assets	**63,060,147**	49,089,596
Shareholders' equity	**31,732,229**	19,127,701
Shares outstanding		
Basic	**54,044,420**	45,134,421
Diluted	**57,730,420**	47,663,587
Weighted average shares		
Basic	**48,335,571**	36,505,356
Diluted	**49,285,718**	36,560,469
OPERATIONAL		
Volumes		
Oil and NGLs *(bbls/d)*	**1,192**	809
Natural gas *(mcf/d)*	**10,869**	7,396
Combined *(boe/d, 6:1)*	**3,003**	2,042
Prices		
Oil and NGLs *($/bbl)*	**26.93**	27.36
Natural gas before hedge *($/mcf)*	**6.53**	3.96
Natural gas after hedge *($/mcf)*	**6.51**	4.05
Total proved and probable reserves *(mboe, 6:1)* [2]	**7,127**	6,041
Undeveloped land		
Gross acres	**362,493**	270,933
Net acres	**218,244**	153,255
Value	**$ 11,294,349**	$ 11,339,000
Wells drilled		
Gross	**45**	38
Net	**29.5**	17.8
Net success rate *(%)*	**91**	74

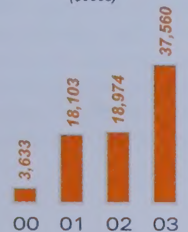
[1] *Funds flow from operations includes prepaid gas revenue.*

[2] *Using January 1, 2003 established gross Company Interest reserves as the comparison to January 1, 2004 proved and probable gross Working Interest reserves to reflect the difference in the risk applied to those reserves as a result of the NI 51-101 requirements.*

Production
(boe/d, 6:1)

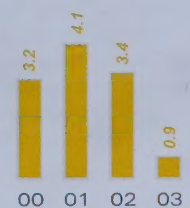


Revenue
($000s)



Cash Flow
Per Share
($)

Debt to
Cash Flow Ratio



PAUL R. BAAY,
PRESIDENT & CEO

The year 2003 was a landmark year for True Energy Inc. True continues to progress as a financially-disciplined exploration-driven natural gas focused producer. The expertise of our senior management along with our dynamic team of employees, consultants and Board of Directors has helped build a fundamentally solid growth-based oil and gas organization. In all four of the Company's key discipline areas - exploration, finance, land, and operations - the results were dramatic.

Our exploration team achieved a 91% net drilling success in 2003, executing our strategy of significant growth through the drill bit. We high graded our projects, focusing on those that would yield maximum production, reserves and cash flow. We exceeded our target year end exit production rate by 310 boe/d, reaching 4,140 boe/d. Simultaneously, we continued to lay the foundation for 2004 and beyond, diversifying our opportunities into Alberta. We hired additional Alberta natural gas expertise, supplementing the extensive experience and skill sets of our people. With the addition of Alberta-based exploration prospects to the extensive inventory our Saskatchewan team has accumulated, we now have a two-year drilling inventory from which 56 wells are expected to be drilled this year.

In the land area we have aggregated an enviable land position for a junior exploration company - over 218,000 net undeveloped acres at December 31, 2003, of which 41,300 net acres are freehold lands. In addition, we have access to another 91,180 acres and significant seismic data through farm-in agreements in our west central Saskatchewan and west central Alberta core areas. I believe that undeveloped land is essential, providing future exploration-oriented opportunities integral to building a long-term successful oil and gas company.

In the financial area we achieved financial flexibility through disciplined improvement of the Company's balance sheet. We enhanced financial discipline, taking the Company from over 3.4 times historical debt to cash flow at the end of 2002 to 0.9 times by the end of 2003. We have instituted strict cost control measures and continually monitor capital expenditures based on cash flow.

Our operations team maximized drilling costs efficiencies, turning in finding and development costs of $11/boe. Our production operations' emphasis on critical path planning, in one instance, achieved a record 36 hours between rig release and on-stream time. We completed our fourth natural gas processing facility in Saskatchewan, as we strive to maximize profitability by balancing excess versus insufficient capacity at our operated gas processing facilities. These efforts combined resulted in both financial and production results that were record setting for the Company.

During 2003 we undertook an enhanced investor relations program to communicate this message to the market place. We visited the main financial centers within Canada and the United States, as well as smaller centers within Canada, meeting with retail and institutional investors at various industry conferences and forums. We are cognizant that liquidity is very important for retail and institutional investors - often small cap junior oil and gas companies are easy to get into and hard to get out of. We believe our investor relations activities have prompted our share trading volumes to increase to approximately 280,000 shares per day during the first quarter of 2004. Recently we attained a market capitalization of approximately $100 million, reaching a threshold where the Company is now more attractive to certain institutional and fund investors. We believe this is an important milestone as we cultivate a strong market following.

OUTLOOK FOR 2004 AND BEYOND

Our business strategy continues to be threefold. We will pursue shallow gas and profitable heavy oil plays in Saskatchewan, complemented by the deeper liquids-rich longer reserve life natural gas targets in Alberta. Our results in 2003 are testimony to the successful implementation of our business strategy as we strive for excellence.

In our core Saskatchewan fairway we are striving for enhanced operational efficiencies by reducing operating costs below 2003 levels. We believe this target is achievable through our attention to operational detail and maximizing the utilization of our facilities. West central Saskatchewan is the main producing area of the Company, with the combination of shallow gas drilling programs along with high-graded oil opportunities.

Operationally, we will be increasing our Alberta drilling operations. During the past 18 months we have acquired a significant land position with facility capacity in this area. We now want to increase our drilling activity through additional Company operated opportunities.

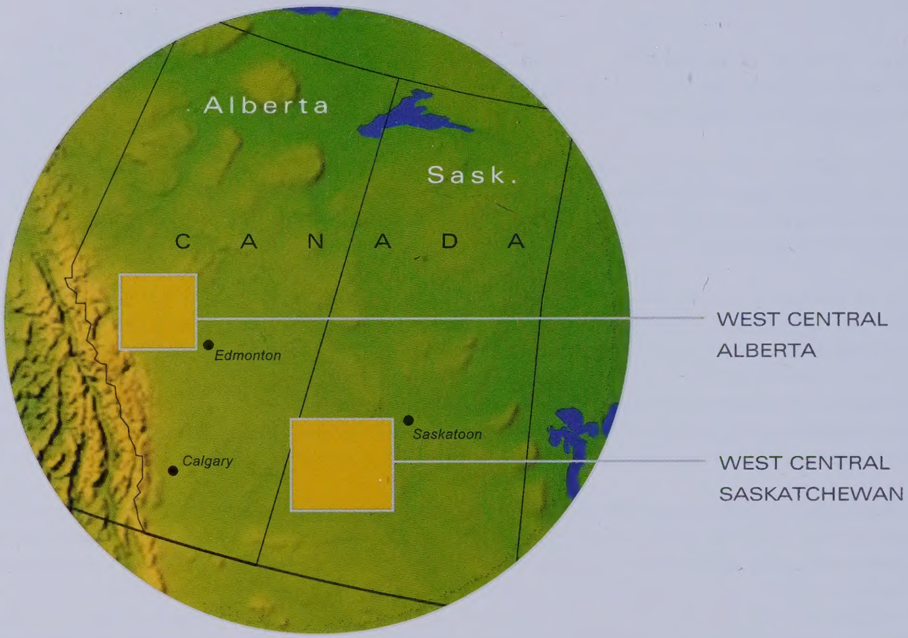
In addition to our medium-risk exploration programs in Alberta and Saskatchewan, we expect to participate in up to four high-impact drilling opportunities in the coming year. We believe our disciplined growth strategy will allow production from our defined core areas to surpass 5,000 boe/d. We believe we have the team and expertise to achieve this objective.

Commodity forecasting is becoming increasingly difficult due to the high degree of volatility we have seen in both the oil and natural gas markets during the past three years. We will mitigate seasonal volatile commodity swings with low operating costs and a strong balance sheet. Financial discipline will be our main instrument to ensure long-term growth and success of the Company.

CONCLUSION

The past year was a year of significant achievement for us. We have established a firm foundation for future growth. As President, I find it rewarding to be involved with a team of motivated staff whose interests are clearly aligned with those of shareholders. I am delighted firstly that the results have added value in all key areas, and secondly, that the added value is being recognized by significant appreciation in the Company's share price. It has been a pleasure to see the success take place and I look forward to the continued results through 2004.

Paul R. Baay
President and CEO
March 26, 2004



True Energy operates in two focused areas within west central Saskatchewan and west central Alberta. The primary properties in Saskatchewan are the Dodsland / Druid, Smiley, Kerrobert, Coleville Driver, and the Coleville South areas, and in Alberta, the Rosevear, Doris and Whitecourt areas.

True has grown its undeveloped land inventory to more than 218,000 net acres. The Company's proved and probable reserves have reached 7,127 mboe by the end of 2003, weighted 61% natural gas, 32% heavy crude and 7% light crude and NGLs. From inception production rates of 354 boe/d, True exited 2003 at 4,140 boe/d, and is currently producing approximately 4,800 boe/d. The Company anticipates average production rates for 2004 to be in the 4,500 to 5,000 boe/d range, depending upon drilling success.

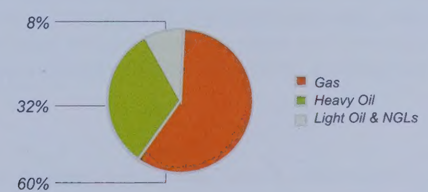
True produced an average of 3,003 boe/d during 2003. Natural gas sales of 10,869 mcf/d, or 60% of total sales in the year, grew 47% over 2002 levels. Sales of crude oil and natural gas liquids also grew proportionately, increasing by 383 bbls/d.

AVERAGE 2003 PRODUCTION

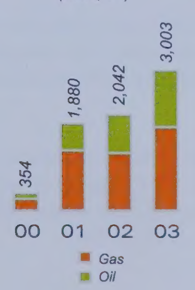
	Natural Gas (mcf/d)	Heavy Oil (bbls/d)	Light Oil and NGLs (bbls/d)	Total (boe/d, 6:1)
Saskatchewan				
Kerrobert	-	523	106	629
Dodsland / Druid	2,979	-	40	536
Smiley	2,069	105	-	450
Coleville Driver	2,610	-	-	435
Coleville South	-	299	-	299
Minor properties	269	37	24	106
Subtotal	7,927	964	170	2,455
Alberta				
Rosevear	1,878	-	55	368
Doris	907	-	3	154
Minor properties	157	-	-	26
Subtotal	2,942	-	58	548
Total	10,869	964	228	3,003
Contribution	60%	32%	8%	100%

As at December 31, 2003, True had interests in 57.22 net producing natural gas wells and 81.56 net producing oil wells, a total of 138.78 net producing wells.

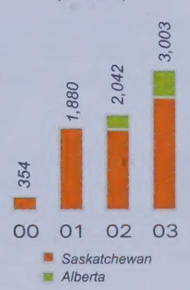
Commodity Mix

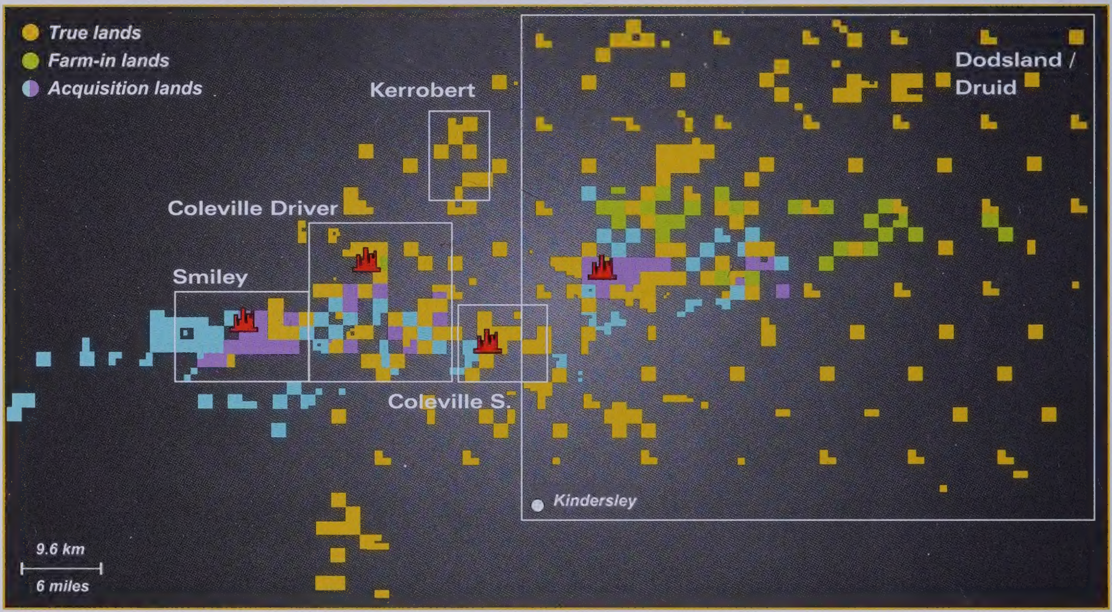


Production by Commodity
(boe/d, 6:1)



Production by Area
(boe/d, 6:1)





WEST CENTRAL SASKATCHEWAN

When True began operations on September 1, 2000 in west central Saskatchewan, production averaged 354 boe/d. Since that time, the Company has expanded its operations through conventional drilling, farm-in agreements, asset and corporate acquisitions, and successful bidding at Crown land sales. During 2003, True drilled 38 (25.9 net) wells in the province, with a 94% net success rate. By the end of 2003, True had accumulated a total of 39,362 net developed and 105,714 net undeveloped acres. Currently, True produces approximately 4,200 boe/d, weighted 60% toward natural gas. In 2004, the Company anticipates drilling 42 (35.4 net) wells, weighted 80/20 toward natural gas to heavy oil.

Kerrobert

Kerrobert is located approximately 40 kilometres north of the town of Kindersley. With average production rates during 2003 of 629 boe/d, Kerrobert was the most significant producing area for True, representing 21% of total production. The Kerrobert area produces light oil from the Viking formation and 11 degree API heavy oil from the McLaren formation. During 2003, sales of light crude oil averaged 106 bbls/d and heavy oil generated 523 bbls/d. In comparison in 2002, production from Kerrobert averaged 316 boe/d.

During 2003, True drilled 10 (5.5 net) Viking light oil wells, 4 (4.0 net) McLaren horizontal oil wells, and re-completed 2 (2.0 net) light oil wells in the Kerrobert area, all of which are on-stream. Mid-year, True also drilled three stratigraphic test wells to help delineate the McLaren pool boundaries. The Company anticipates drilling four additional McLaren horizontal wells in 2004.

True initially acquired its interest in the Kerrobert area through a 2001 property acquisition, then subsequently re-activated two McLaren formation wells, including one horizontal well. In 2002, the Company drilled two successful 100% horizontal heavy oil wells, utilizing three-dimensional seismic acquired covering the main portion of the pool. In December of 2002, ten Viking light oil wells were drilled, then completed and equipped in January 2003.

With the geological information provided from the 2003 drilling of an additional four horizontal wells and three stratigraphic test wells, the McLaren channel is indicated to be more extensive than originally thought. Currently the Company believes further development of the McLaren channel could include the drilling of an additional four to eight horizontal and four to six vertical wells. Longer term, the McLaren channel wells are candidates for steam assisted gravity drainage ("SAGD") enhanced recovery technology, which could significantly increase the overall recovery of the heavy oil from current levels. In the Viking formation, the Company has identified up to 40 additional drillable locations. Projects within the Kerrobert area have longer term reserves with excellent finding costs and low operating expenses.

Dodsland / Druid

The Dodsland / Druid area is located approximately 30 kilometres north of Kindersley. In 2001, an operated 68.8% working interest in the Dodsland Viking Gas Unit was purchased along with a large block of undeveloped land. In 2002, True increased its holdings in the Unit to 81.9%, and in 2003 further increased it to 89.2%. Unit facilities include an owned and operated 3 mmcf/d capacity natural gas facility with compression, dehydration and liquids extraction capabilities, handling Unit and non-Unit gas production from the Viking and Bakken formations.

The Company's geological understanding has progressed significantly in the past year with the combination of extensive two-dimensional seismic and additional new drilling. At year end 2003, True has approximately 67,900 net undeveloped acres in the area, of which approximately 43,600 acres is freehold.

The Dodsland / Druid property produces primarily natural gas, making up 27% of the Company total, and some field condensate. During 2003, sales of natural gas averaged 2,979 mcf/d complemented by 40 bbls/d of light crude. With total production rates from the area of 536 boe/d, Dodsland / Druid contributed the second largest volumes for True's account. The Company has been very active in the Dodsland / Druid area during 2003, accounting for the growth in production from average sales in 2002 of 109 boe/d.

During 2003, the Company drilled 7 (6.4 net) natural gas wells and 1 (1.0 net) dry hole. Five of these wells are now on production, with the remaining two expected to be tied-in this year. During the first quarter of 2004, True has drilled and tied- in an additional 10 Viking gas wells and currently anticipates drilling another 10 during the second quarter.

Currently, the Company is focusing on determining the extent of the natural gas pool through delineation drilling using single section spacing units. True has not pursued to date the significant infill drilling potential that may exist through down spacing.

Smiley

The Smiley property is located about 35 kilometres northwest of Kindersley, producing natural gas, light and heavy oil. Targeted formations in the Smiley area include the Viking, Colony, Waseca, Detrital and Bakken zones at depths of 700 to 900 metres. In 2001, the Company constructed a natural gas compression, dehydration and sweetening facility (capable of 4 mmcf/d). During 2003, True drilled 5 (2.9 net) natural gas wells and 5 (2.5 net) heavy oil wells, plus conducted the re-completion and work-over of one natural gas and one heavy oil well. All wells are on production. Late in 2003, the capacity at the Smiley gas plant was upgraded to handle approximately 6 mmcf/d.

During 2003, production averaged 2,069 mcf/d of natural gas and 105 bbls/d of heavy oil, totaling 450 boe/d, up 31% from average sales during 2002 of 343 boe/d. True has drilled 2 (0.5 net) Bakken heavy oil wells in the first quarter of 2004.

Coleville Driver

The Coleville Driver area, located 25 kilometres northwest of Kindersley, produces natural gas from shallow 700 to 825 meter Bakken and Mannville zones. Natural gas sales in 2003 averaged 2,610 mcf/d, or 435 boe/d, similar to the 420 boe/d produced during 2002. Coleville Driver operated facilities include a natural gas compressor station with dehydration and sweetening capabilities running close to capacity at current inlet pipeline pressures. During 2003, True negotiated the purchase of the remaining 20% working interest in this facility.

During 2003, the Company drilled 3 (2.5 net) developmental natural gas drilling locations. With additional lands purchased and seismic being shot during 2004, the area remains an active exploitation and exploration area for the Company, allowing the production capacity to be utilized for years to come.

Coleville South

The Coleville South area, located 18 kilometres north of Kindersley, conventionally produces primarily 11 degree API heavy crude oil from the Bakken formation. Each well is equipped with a screw pump and heated treating and storage tanks. The Coleville South developmental farm-in program began in 2001 with the drilling of an initial eight wells adjacent to an existing Bakken heavy oil pool located on non-interest lands. During 2002, True further evaluated and delineated the pool, drilling 16 additional oil developmental wells in conjunction with two- and three-dimensional seismic. The Company drilled 1 (0.5 net) Detrital natural gas well during 2003. This well was tied-in along with solution gas from the area heavy oil wells to True's fourth Saskatchewan gas processing facility which was constructed at the end of 2003.

Sales of heavy oil during 2003 averaged 299 bbls/d, 6% less than the 318 bbls/d produced during 2002. Current natural gas production rates are 2.0 (1.0 net to True) mmcf/d.

Based on three-dimensional seismic, ultimate full development of the project could include 50 to 60 wells, of which approximately 12 would be re-completed as water injector wells, complemented by central treating and water handling facilities and the implementation of a waterflood. During the first quarter of 2004, True drilled 3 (1.5 net) wells in the area, of which 2 (1.0) are Bakken heavy oil wells, now on production.

WEST CENTRAL ALBERTA

The strategic objective of creating a second core area located in west central Alberta to complement the existing west central Saskatchewan core area was achieved mid-2002 with the acquisition of Gresham Resources Inc., bringing the non-operated natural gas producing properties at Rosevear and Doris. The exploration team was expanded with professionals with a successful track record of Alberta discoveries, as the Company actively began searching for natural gas within this new core area.

During 2003, True aggressively enhanced the Company's Alberta land position with successful bidding at Crown land sales and a small land acquisition. In addition, the Company entered into a significant rolling farm-in arrangement with an industry competitor, allowing True access to approximately 85,000 net acres and an extensive seismic library. Under the first phase of the agreement, the Company committed to drill four wells by mid-March 2004 to earn three gross sections per well. The Company has just completed this first phase with the drilling of the four earning wells, and is poised to enter into a second commitment / earning phase of the agreement.

In 2003, True drilled 7 (3.6 net) wells in Alberta with a 61% net success rate. By the end of 2003, True had accumulated a total of 26,755 net developed and 112,530 net undeveloped acres within Alberta. Currently the Company produces approximately 600 boe/d, weighted 92% toward natural gas. True expects to drill 14 (6.6 net) gas wells in Alberta during 2004.

Rosevear

Rosevear is approximately 15 kilometres east of Edson. With up to 14 different zones contributing to production, the main producing horizon is liquids-rich Viking at a depth of approximately 2,000 metres. Subsequent to True's purchase of its initial gas interest in Rosevear via Gresham, the Company followed up by drilling one natural gas well and re-completing another during the fourth quarter of 2002. During 2003, True re-completed 2 producing natural gas wells and drilled 2 (0.48 net) natural gas wells, with both wells now on-stream. True plans to participate in one well in this area during the first half of 2004.

With the mid-year acquisition of Rosevear, production to True averaged 184 boe/d during 2002. With a full year of operations, sales during 2003 averaged 368 boe/d, weighted 85% toward natural gas. Rosevear is True's highest netback property, contributing $5.19/mcf from natural gas and $17.63/bbl from liquids.

Doris

Located approximately 160 kilometres northwest of Edmonton, the Doris area produces natural gas primarily from Lower Mannville sands at 1,400 metres.

True's entry mid-year 2002 into the Doris area via the Gresham acquisition contributed 84 boe/d toward True's aggregate production. During 2003, the production of 907 mcf/d of natural gas and 3 bbls/d of natural gas liquids totaled 154 boe/d.

North of Doris, at the end of the first quarter of 2004, True drilled 2 (2.0 net) unsuccessful wells at Parker. In the Roche area, located between Parker and Doris, True participated in 3 (1.0 net) wells during the first quarter of 2004. Two wells were completed, but True does not anticipate any immediate revenue from these wells.

Whitecourt

During the fourth quarter of 2003, True participated in 1 (0.25 net) successful multi-zone natural gas well at Goodwin. By early 2004, two zones were on production. During the first quarter of 2004 2 (0.21 net) wells targeting natural gas were drilled at Goodwin, of which one was dry and the other is producing. Another three natural gas wells are expected to be drilled during the balance of the year.

OTHER MINOR

True's Elkton gas target at Lochend, drilled during the last quarter of 2003, was completed but despite encountering gas, is currently not thought to contain sufficient quantities of hydrocarbons to warrant incurring the significant equipping and pipeline costs required to place this well on production. The Company is currently evaluating another significant potential drilling location on Company lands in this immediate area.

At Donalda, located 130 kilometres southeast of Edmonton, True drilled two 100% working interest wells during 2003; one well was subsequently abandoned, and the other well is currently producing a facilities restricted 157 mcf/d of natural gas. Subsequent to year end, an industry competitor has farmed onto Company lands in the area, pursuing coalbed methane potential.

Gresham Resources had developed a number of exploration concepts and potential drilling locations in the Peace River Arch area of Alberta, located north of the Company's operations. Consistent with True's decision to focus within west central Alberta on medium-risk multi-zone, high netback liquids-rich natural gas and light oil plays, these higher-risk opportunities outside our core area have been farmed-out to industry competitors. True has retained varying interests in these farmed out locations allowing the Company to participate in any potential upside of discoveries without incurring the exploration risk.

LAND HOLDINGS

True's philosophy of primary growth through the drill bit is reliant upon continual prospect generation. This process is complemented by a significant undeveloped land base. In addition to owning approximately 41,300 net acres of freehold lands (not subject to expiry issues), the Company has been aggressively pursuing farm-in opportunities. The Company believes farm-in agreements provide True with land and, frequently, seismic at much lower cost than Crown land sales or seismic acquisitions.

During 2003, True added approximately 65,000 net undeveloped acres (75% in Alberta), to its land inventory by earning lands through farm-in agreements, Crown land sales, and purchases from industry competitors.

In a report prepared by Seaton-Jordan & Associates Ltd. effective January 1, 2004, the value of True's undeveloped land inventory was established at $11,294,349. This was determined in accordance with the provisions of NI 51-101 based on the first applicable of the following factors:

The acquisition cost, provided that there have been no material changes in the unproved property, the surrounding properties, or the general oil and gas climate since the acquisition.
Recent sales by others of interests in the same unproved property.
Terms and conditions, expressed in monetary terms, of recent farm-in agreements.
Terms and conditions, expressed in monetary terms, or recent work commitments related to the unproved property.
Recent sales of similar properties in the same general area.

The value of the Company's holdings in 2002 was determined internally by reviewing land sales in each area during the past year.

Land Statistics	*2003*	*2002*
Average working interest		
Developed	**53%**	51%
Undeveloped	**60%**	57%
Total	**58%**	55%
Value of undeveloped land	**$ 11,294,349**	$ 11,339,000
Value per net undeveloped acre	**$ 52**	$ 74

	2003		*2002*	
Land Holdings (acres)	*Gross*	*Net*	*Gross*	*Net*
Developed				
Alberta	**59,251**	**26,755**	55,211	23,874
Saskatchewan	**66,594**	**39,362**	73,771	41,949
Total	**125,845**	**66,117**	128,982	65,823
Undeveloped				
Alberta	**209,617**	**112,530**	117,559	62,749
Saskatchewan	**152,876**	**105,714**	153,374	90,506
Total	**362,493**	**218,244**	270,933	153,255
Total				
Alberta	**268,868**	**139,285**	172,770	86,623
Saskatchewan	**219,470**	**145,076**	227,145	132,455
Total	**488,338**	**284,361**	399,915	219,078

DRILLING ACTIVITY

Shortly after the formation of True Energy in September 2000, the Company was successful in purchasing significant undeveloped lands. This acquisition provided the cornerstone for the Company to develop current significant operations in the west central Saskatchewan area. With subsequent soft commodity prices, True's balance sheet became strained, restricting the Company's ability to carry out anything more than modest developmental drilling. The year 2003 was a significant turning point. With the restoration of a healthy balance sheet, the Company was able to embark on a full fledged exploration and development program.

In 2003, True, utilizing portfolio management, selected a mix of low to medium-risk projects with similar costs and scope. Higher risk wells, or corporate accelerators, are usually drilled by bringing in working interest partners, helping to reduce the total exposure to the Company. During the year, True drilled or participated in a record 45 wells, at a net 91% success rate. The rewards for this accomplishment are reflected in the production growth, exiting 2003 at 4,140 boe/d.

Drilling Summary *(number of wells)*	***2003***	***2002***
Gross	**45**	38
Net	**29.5**	17.8
Net success rate *(%)*	**91**	74

Drilling Results by Province *(number of wells)*	***Gross***	***Net***
Saskatchewan		
Gas	17	12.6
Light oil	10	5.5
Heavy oil	9	6.5
Dry and abandoned	2	1.3
Total	38	25.9
Alberta		
Gas	5	2.2
Light oil	-	-
Heavy oil	-	-
Dry and abandoned	2	1.4
Total	7	3.6
Total		
Gas	22	14.8
Light oil	10	5.5
Heavy oil	9	6.5
Dry and abandoned	4	2.7
Total	45	29.5

During the first quarter of 2004, True has drilled or participated in 23 (16.2 net) wells at a net success rate of 77%, with16 (13.0 net) wells in Saskatchewan and 7 (3.2 net) wells in Alberta.

RESERVES

True's reserves were evaluated by Gilbert Laustsen Jung Associates Ltd. ("GLJ") effective as at January 1, 2004 in a report dated March 19, 2004. The Reserve Committee of the Board of Directors, consisting entirely of independent directors, has met with a representative of GLJ and has reviewed the report in accordance with its mandate.

The GLJ report was prepared in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). This new instrument adopted by the Canadian Securities Administrators sets out standards of disclosure for oil and gas activities and mandates the application of evaluation standards defined in the Society of Petroleum Evaluation Engineers (SPEE) Canadian Oil and Gas Evaluation Handbook (COGEH). The information that follows has been derived from the GLJ report.

The estimates of reserves are subject to revisions as additional reservoir and performance information become available, and contain judgments of future events for which the actual results may vary materially. The estimated future net revenues are before future site restoration costs and include the Alberta Royalty Tax Credit, but are reduced for estimated future abandonment costs and the Saskatchewan Capital Tax costs.

Prior to the implementation of NI 51-101, True reported and reconciled reserves on a "Company Interest" basis (working interest reserves before deduction of royalty burdens payable plus royalty interest reserves, being lessor royalty and overriding royalty volumes derived only from other working interest owners). Under NI 51-101, reserves are to be disclosed on both a "Working Interest" basis (being working interest reserves, excluding royalties interest reserves before deduction of royalty burdens payable) and a "Net Interest" basis (being working interest reserves and royalties receivable less royalty burdens payable). Working Interest reserves equate to "Gross" reserves in NI 51-101. The difference to True between the Company Interest and Working Interest volumes is less than one percent for both proved, and proved and probable, reserves. The reader is referred to the Company's Annual Information Form, which will be filed before the end of May 2004 for complete NI 51-101 disclosure and will be available on the Company's website and on SEDAR. This Annual Report contains Working Interest (Gross Interest) and Net Interest reserves determined using GLJ's January 1, 2004 price forecast.

Summary of Oil and Gas Reserves [1]
As at January 1, 2004
Forecast Prices and Costs

	Light & Medium Oil (mbbl)		Heavy Oil (mbbl)		Natural Gas (mmcf)		Natural Gas Liquids (mbbl)		Total (mboe, 6:1)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved										
Developed producing	266.0	251.2	1,426.9	1,184.4	16,920	13,319	134.8	106.1	4,647.8	3,761.6
Developed non-producing	-	-	24.5	20.4	2,294	1,920	25.0	18.3	431.8	358.8
Undeveloped	-	-	-	-	618	436	2.2	1.5	105.2	74.1
Total proved	266.0	251.2	1,451.3	1,204.9	19,833	15,675	162.0	125.9	5,184.8	4,194.5
Probable	45.3	42.5	808.4	669.8	6,287	4,893	40.9	29.6	1,942.5	1,557.3
Total proved plus probable	311.3	293.7	2,259.8	1,874.7	26,120	20,568	203.0	155.5	7,127.3	5,751.8

[1] *May not add due to rounding.*

***Summary of Net Present Values of Future Net Revenue*[1]**
As at January 1, 2004
Forecast Prices and Costs

	Before Income Taxes Discounted at (%/year) 0% ($mm)	Before Income Taxes Discounted at (%/year) 10% ($mm)	After Income Taxes Discounted at (%/year) 0% ($mm)	After Income Taxes Discounted at (%/year) 10% ($mm)
Proved				
Developed producing	63,468	50,122	51,779	40,076
Developed non-producing	5,972	3,479	4,169	2,180
Undeveloped	1,515	1,368	710	593
Total proved	70,955	54,970	56,658	42,849
Probable	21,765	12,248	13,693	7,178
Total proved plus probable	92,720	67,218	70,350	50,027

[1] *May not add due to rounding; future net revenue values do not represent fair value.*

RESERVE LIFE INDEX

The reserve life index is calculated by dividing year end reserves by the average production during the past year to estimate the number of years of remaining production. Based upon the year end reserve volumes and the average 2003 production rate for True Energy, sufficient reserves exist to continue production at the current rate for approximately six and a half years based on proved and probable reserves, and five years based on proved reserves.

Reserve Life	2003 Proved	2003 Proved & Probable[1]	2002 Proved	2002 Proved & Probable[1]
Natural gas	**5.0**	**6.6**	6.7	10.5
Crude oil and NGLs	**4.3**	**6.4**	5.2	9.6
Total boe	**4.7**	**6.5**	6.1	10.1

[1] *The foregoing utilizes the January 1, 2003 established (proved plus half probable) reserves as the comparison to January 1, 2004 proved and probable reserves to reflect the difference in the risk applied to these reserves as a result of the NI 51-101 requirements, and is based upon GLJ's January 1, 2003 and 2004 price forecasts as applicable.*

RESERVE RECYCLE RATIO

The reserve recycle ratio is calculated by dividing the operating netback (being sales less royalties and operating costs) on a per unit basis by the finding and development cost. This indicator of efficiency measures the deployment of operating cash flow income compared to reserve additions.

	2003	2002
Operating netback *($/boe)*	**18.15**	12.60
Proved basis	**1.5**	1.4
Proved and probable basis[1]	**1.5**	1.8

[1] *The foregoing utilizes the January 1, 2003 established (proved plus half probable) reserves as the comparison to January 1, 2004 proved and probable reserves to reflect the difference in the risk applied to these reserves as a result of the NI 51-101 requirements, and is based upon GLJ's January 1, 2003 and 2004 price forecasts as applicable.*

PRODUCTION REPLACEMENT RATIO

The production replacement ratio measures the number of times the current year production has been replaced by net reserve additions by dividing the annual production into reserve additions. True's production replacement ratio reflects the operational focus on decreasing overall debt levels while adding reserves at a cost effective rate. In 2003 the ratio also incorporates the impact of more stringent reserve definitions.

	2003	*2002*
Proved basis	**1.6 x**	2.9 x
Proved and probable basis[1]	**2.0 x**	3.7 x

[1] *The foregoing utilizes the January 1, 2003 established (proved plus half probable) reserves as the comparison to January 1, 2004 proved and probable reserves to reflect the difference in the risk applied to these reserves as a result of the NI 51-101 requirements, and is based upon GLJ's January 1, 2003 and 2004 price forecasts as applicable.*

The following Management Discussion and Analysis of the financial results as provided by the management of True Energy Inc. ("True") should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2003 and 2002. All amounts are stated in Canadian dollars unless otherwise noted. This commentary is based on information available to March 26, 2004. Additional information relating to True is available on SEDAR at www.sedar.com. The Company's Annual Information Form ("AIF") will be available on SEDAR by the end of May 2004.

This financial review contains the term cash flow from operations, which should not be considered an alternative to, or more meaningful than cash flow from operations as determined in accordance with Canadian generally accepted accounting principles ("GAAP") as an indicator of the Company's operating performance, and may not be comparable to the calculation of similar measures for other entities. The Company presents cash flow from operations per share whereby per share amounts are calculated consistent with the calculation of earnings per share. The consolidated statements of cash flows in the audited consolidated financial statements present the reconciliation between net earnings and cash flow from operations, and are based on cash flow before changes in non-cash working capital.

BOE's may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet per barrel (6 mcf/ bbl) of natural gas to barrels of oil equivalence is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All boe conversions in this report are derived from converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil.

Financial Highlights of 2003

NET EARNINGS AND CASH FLOW FROM OPERATIONS

True generated cash flow from operations of $15.8 million for the year ended December 31, 2003, up 167% from the $5.9 million produced in the same period of 2002. Cash flow from operations per basic and diluted share approximately doubled in the corresponding periods. Comparatively higher commodity prices and growth in the Company's sales volumes over the same period in 2002 were the primary factors contributing to the increases.

Net earnings for 2003 were $4.3 million compared to $0.2 million in 2002, reflective of the increased prices and sales volumes. Basic and diluted per share earnings grew from $0.01 in 2002 to $0.09 in 2003. This growth in earnings during 2003 compared to the prior year primarily reflects the increased cash flow from operations.

SALES VOLUMES

Average sales volumes on a year-over-year basis in 2003 have grown by 47% compared to 2002. During 2003, the Company more than replaced production declines as a result of drilling successes, achieving exit production rates by the end of the year of 4,140 boe/d, weighted approximately 60% toward natural gas. Sales volumes for all three commodities were higher, although the mix remained exactly the same in 2003 compared to 2002 - 60% natural gas, 32% heavy oil, and 8% light oil and NGLs.

Sales by Commodity	*2003*	*2002*
Natural gas *(mcf/d)*	**10,869**	7,396
Heavy oil *(bbls/d)*	**964**	656
Light oil and NGLs *(bbls/d)*	**228**	153
Total oil and NGLs *(bbls/d)*	**1,192**	809
Total *(boe, 6:1)*	**3,003**	2,042

Average sales of natural gas in 2003 grew 47% from 7.4 mmcf/d in 2002 to 10.9 mmcf/d. Three wells drilled and placed on production during 2003 in the Dodsland / Druid and Smiley areas of Saskatchewan plus a full year of production from another well drilled late in 2002 accounted for an incremental 2.4 mmcf/d of natural gas sales during 2003. In Alberta, a full year of production from the August 2002 Gresham Resources Inc. ("Gresham") acquisition primarily accounted for an additional 1.4 mmcf/d over average 2002 sales. True's natural gas production rate at the very end of 2003 was 14.9 mmcf/d, with four additional natural gas wells in the Dodsland / Druid area to be tied-in during 2004. Currently two of these four are on-stream.

Crude oil sales increased in 2003 compared to the prior year with approximately 313 bbls/d of additional production from the Kerrobert area, with four horizontal heavy oil wells adding approximately 283 bbls/d and 10 light oil wells contributing 30 bbls/d.

Commodity Prices	*2003*	*2002*	*% Change*
Exchange rate *(US$/Cdn$)*	**0.7164**	0.6371	12%
NYMEX *(US$/mmbtu)*	**5.50**	3.36	64%
Alberta spot *($/mcf)*	**6.50**	3.96	64%
Natural gas before hedge *($/mcf)*	**6.53**	3.96	65%
Natural gas after hedge *($/mcf)*	**6.51**	4.05	61%
WTI *(US$/bbl)*	**31.10**	26.13	19%
Edmonton par light oil *($/bbl)*	**43.39**	40.20	8%
Bow River heavy oil *($/bbl)*	**32.38**	31.77	2%
Heavy crude oil *($/bbl)*	**23.92**	25.38	(6%)
Light crude oil and NGLs *($/bbl)*	**39.68**	35.84	11%
Crude oil and NGLs *($/bbl)*	**26.93**	27.36	(2%)

True received $6.53/mcf for its natural gas before hedges during 2003, up 65% from the average of $3.96/mcf received in 2002, paralleling the change in Alberta spot prices. The Company's natural gas is primarily sold on the daily spot market.

For the Company's light crude oil and natural gas liquids, the average price received in 2003 was $39.68/bbl, up 11% compared to the prior year. Similarly, the average Edmonton par price increased over this same period by 8%.

For heavy oil, differentials between heavy and light crude oil prices widened in 2003 driven by lower asphalt demand in 2003 and additional Canadian heavy crude oil coming on-stream. True's heavy oil sales averaged $23.92/bbl in 2003, down 6% in comparison to 2002, while the average price for Bow River heavy crude increased by 2% over this same period. The Company's price is after adjustments for condensate blending and pipeline tariffs, with the net price received directly proportional to the cost of condensate blending. True's price in 2002 averaged approximately 80% of the net Bow River price. In 2003, the Company received an average of 74% of the Bow River price, the reduction attributable to increased sales from the Kerrobert McLaren field which requires an increased condensate blending charge.

REVENUE

Revenue for 2003 was $37.6 million, 98% greater than the $19.0 million generated in the same period in 2002. Natural gas sales grew by 144%, reflecting 47% more daily sales volumes combined with a price increase of 65% before hedges. Sales for crude oil and NGLs were 45% higher, the net effect of a 47% increase in heavy and light crude oil and NGL volumes, partially offset by a 6% decrease in heavy oil prices received.

Revenue *($000s)*	*2003*	*2002*
Crude oil and NGLs	**11,715**	8,083
Natural gas	**25,903**	10,636
Natural gas hedge	**(58)**	255
Total	**37,560**	18,974

HEDGING

True had a natural gas commodity price swap for 3,000 gigajoules per day for the period April 1, 2003 to October 31, 2003 based on an AECO "C" price of Cdn$6.08 per gigajoule. Over the period of the contract, True incurred a net cost of $57,861. Currently, the Company has no hedges in place.

ROYALTIES

For the year ended December 31, 2003, total royalties were $9.5 million, up 113% from 2002 in aggregate and by royalty type for Crown royalties and freehold / GORR. Alberta Royalty Tax Credit (ARTC) increased a similar 108%. True's royalty rate in 2003 has remained relatively unchanged at 25% of gross sales compared to 24% in the prior year, with natural gas increasing by 1% to 27%, and crude oil and NGLs flat at 21%.

On a per unit basis, natural gas royalties increased by 73% in 2003 to $1.78/mcf compared to $1.03/mcf in 2002, primarily reflecting the 65% higher natural gas prices. For crude oil and NGLs, the 2% decline in the average price received for these commodities resulted in an average cost of $5.68/bbl for royalties in both 2003 and 2002.

Royalties by Type *($000s)*	*2003*	*2002*
Crown royalties	**6,228**	2,917
Freehold and GORR	**3,495**	1,646
Alberta Royalty Tax Credit	**(206)**	(99)
Total	**9,517**	4,464

OPERATING EXPENSES

For the year ended December 31, 2003, operating costs totaled $8.2 million, up 59% from the $5.1 million recorded in the same period of 2002. On a barrel of oil equivalent basis, operating expenses in 2003 averaged $7.44, up $0.57, or 8% compared to $6.87 for 2002.

Weather was a significant factor in high operating costs during the first half of 2003. True has traditionally had higher operating costs during the winter and spring months compared to the summer months. In 2003, this pattern was more pronounced due to harsher and more extended spring break-up conditions than usual, resulting in approximately $0.22/boe of incremental costs for related well service costs. Costs were incurred for incremental gas gathering and processing charges ($0.18/boe), a provision to settle a processing dispute ($0.14/boe), and increased compressor rentals ($0.26/boe) primarily in the Dodsland / Druid area to process additional gas volumes, partially offset by a reduction in non-operated overhead charges ($0.31/boe) as the Company increasingly operates a greater portion of its operations.

Production Costs by Commodity Type *($000s)*	*2003*	*2002*
Crude oil and NGLs	**3,456**	2,835
Natural gas	**4,695**	2,284
Total	**8,151**	5,119

OPERATING NETBACKS

Operating per unit netbacks for True improved in 2003 by 44% in comparison to 2002, driven by higher natural gas prices partially offset by marginally greater operating costs and proportionate royalty costs.

Operating Netbacks	*Natural Gas* *($/mcf)*		*Crude Oil and NGLs* *($/bbl)*		*Total* *($/boe)*	
	2003	*2002*	*2003*	*2002*	*2003*	*2002*
Sales	**6.53**	3.96	**26.93**	27.36	**34.27**	25.46
Hedge	**(0.01)**	0.09	**-**	-	**-**	-
Royalties	**(1.78)**	(1.03)	**(5.68)**	(5.68)	**(8.68)**	(5.99)
Production expense	**(1.18)**	(0.85)	**(7.95)**	(9.60)	**(7.44)**	(6.87)
Field operating netback	**3.56**	2.17	**13.30**	12.08	**18.15**	12.60

GENERAL AND ADMINISTRATIVE

Gross general and administrative costs for 2003 were $4.7 million, up $1.6 million compared to $3.1 million in 2002. Salaries and wages cost the Company an additional $0.9 million with the addition of six new employees, plus increased salaries and severance costs. With the additional people, True moved into new office space but was unable to find a subtenant for the old space for five months. Rent, business taxes and charges relating to the office move added an incremental $0.3 million of costs. The early adoption of the Amended Stock Compensation reporting requirements added costs of $0.2 million.

True reduces the total general and administrative costs by charges allocated to the Company's capital and operating projects. For 2003, recoveries totaled $1.1 million compared to $0.7 million in 2002. In addition, True capitalizes those direct costs incurred by exploration-focused personnel. Salaries and benefits for field personnel are charged to the related projects in which they are involved. During 2003, True capitalized $0.9 million during 2003, with severance costs accounting for $0.3 million.

General and Administrative Costs *($000s, except as indicated)*	*2003*	*2002*
Gross costs	**4,676**	3,107
Capitalized	**(884)**	(327)
Recoveries	**(1,082)**	(652)
Net costs	**2,710**	2,128
Net costs, per unit *($/boe)*	**2.47**	2.86

INTEREST EXPENSE

True recorded $0.8 million of interest expense in 2003 and 2002. During 2003, True reduced the indebtedness level of the Company significantly from 3.4 times net debt to historical cash flow at the end of 2002 to 0.9 times by the end of 2003. This was achieved through disciplined capital expenditures, healthy commodity prices and the proceeds of two common share issuances. The Company targets maintaining a maximum annualized net debt to historical cash flow ratio of approximately 1.3 times.

In conjunction with the strengthened balance sheet during 2003, True re-negotiated the cost of borrowing with its lender, a Canadian chartered bank. In 2002 interest was incurred at the bank's prime rate plus 1% to 1½%. Interest is now payable at the lenders' prime rate plus an applicable margin, as outlined in the lending agreement, which is based on the debt to cash flow ratio. With the decreased debt to cash flow ratio, this represents significant savings to the Company.

Interest Costs	*2003*	*2002*
Interest expense *($000s)*	**773**	781
Interest *($/boe)*	**0.71**	1.05
Year end net debt *($000s)*	**14,461**	19,893
Net debt to historical cash flow ratio	**0.9x**	3.4x

CAPITAL EXPENDITURES

Capital expenditures in 2003 of $20.0 million were primarily spent on oil and gas exploration and development activities, drilling or participating in 45 (29.5 net) wells at a net 91% success rate. During the year, True increased its overall land position by approximately 65,000 net undeveloped acres, three-quarters in Alberta and the balance in Saskatchewan. At the end of the year, True completed a fourth Saskatchewan gas processing facility at Coleville South and added compression at Smiley. In comparison, in 2002 the Company spent a total of $18.8 million, drilling 38 (17.8 net) wells, including $14.6 million on the acquisition of Gresham Resources Inc..

Capital Expenditures *($000s)*	*2003*	*2002*
Lease acquisitions and retention	**2,317**	760
Geological and geophysical	**1,050**	1,164
Drilling and completion costs	**12,603**	6,071
Facilities and equipment	**2,396**	1,426
Exploration and development	**18,366**	9,421
Acquisitions	**632**	570
Corporate acquisitions	**-**	14,585
Head office expenditures	**1,042**	604
Total expenditures	**20,040**	25,180
Dispositions	**-**	(6,378)
Net capital expenditures	**20,040**	18,802

At January 1, 2004 True had 362,493 gross (218,244 net) of undeveloped land. In comparison, at January 1, 2003 the Company had 153,255 net acres of undeveloped land.

CEILING TEST

Under the Canadian Institute of Chartered Accountants (CICA) full cost accounting guidelines, the Company calculates a ceiling test quarterly and annually whereby the carrying value of petroleum and natural gas properties is compared to estimated future cash flow from the production of proved reserves.

At December 31, 2003, the Company calculated the ceiling test using prices of $23.07/bbl for oil and $6.50/mcf for natural gas. As a result, the Company has a ceiling test surplus of $16.9 million after tax. For comparative purposes, at December 31, 2002, the Company calculated the ceiling test using prices of $29.04/bbl for oil and $6.18/mcf for natural gas giving a ceiling test surplus of $28.7 million after tax.

FINDING, DEVELOPMENT AND ACQUISITION COSTS

True's all-in finding, development and acquisition costs for 2003, including revisions and future development costs, were $12/boe for both proved and probable and proved. For the three years 2001 through 2003, average all-in costs were $11/boe proved and probable and $13/boe proved.

All-in Finding, Development and Acquisition Cost, Including Future Capital	*Proved*	*Proved & Probable*
Capital *($000s)*		
Exploration and development capital	19,378	19,378
Acquisition capital	634	634
Disposition capital	28	28
Total capital	20,040	20,040
Future capital, January 1, 2004	1,813	5,957
Future capital, January 1, 2003	0	0
Change in future capital	1,813	5,957
Total, including future capital	21,853	25,997
Reserve net additions *(mboe)*		
Exploration and development reserve additions	1,630	2,206
Acquisition additions	33	36
Dispositions	(175)	(415)
Revisions[1]	261	355
Total reserve net additions	1,749	2,182
All-in finding, development and acquisition cost *($/boe)*	$ 12	$ 12
Average cost for 2001, 2002 and 2003 *($/boe)*	$ 13	$ 11
Finding and Development Costs, Excluding Acquisitions, Including Future Capital		
Capital *($000s)*		
Exploration and development capital	19,378	19,378
Change in future capital	1,813	5,957
	21,191	25,335
Reserve additions, excluding acquisitions, including revisions *(mboe)*		
Exploration and development reserve additions	1,630	2,206
Revisions[1]	261	355
	1,891	2,561
Finding and development costs, excluding acquisitions, including future capital *($/boe)*	$ 11	$ 10
Average cost for 2001, 2002 and 2003 *($/boe)*	$ 10	$ 9
Acquisition Costs, Including Future Capital		
Acquisition capital *($000s)*	634	634
Reserve additions for acquisitions *(mboe)*	33	36
Acquisition costs, including future capital *($/boe)*	$ 19	$ 18
Average cost for 2001, 2002 and 2003 *($/boe)*	$ 14	$ 12

[1] *Reserve additions include the reduction of reserve volumes from excluded royalty interest reserves in accordance with NI 51-101.*

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect True's finding and development costs related to reserves additions for that year.

DEPLETION, DEPRECIATION AND SITE RESTORATION

Depletion, depreciation and site restoration expense for 2003 totaled $8.4 million compared to $5.2 million during 2002. The depletion and depreciation rate for 2003 averaged $7.63 up 10% from the prior fiscal year.

Depletion, Depreciation and Site Restoration *($000s, except as indicated)*	*2003*	*2002*
Depletion	**5,037**	2,615
Depreciation	**2,939**	2,262
Future site restoration	**392**	303
Total	**8,368**	5,180
Per unit *($/boe)*	**7.63**	6.95

INCOME TAXES

Capital taxes paid by the Company are in respect of the Federal Large Corporations Tax and the Saskatchewan Capital Tax. For the year ended December 31, 2003, the provision for capital taxes is $0.8 million. The total long-term liability for capital taxes is $0.8 million as at the end of 2003. Capital tax provision for the year ended December 31, 2002 was $1.2 million, after adjustments for prior years.

During 2003, True has recorded a current income tax recovery of $0.2 million reflecting prior over-estimation of taxes of subsidiary corporations. In 2002, the Company also recorded recovery of prior tax year payments of $0.1 million.

During 2003, there have been substantively enacted changes to the federal and Alberta income tax rates and to deductions for resource income, reducing the rate on resource income, providing for the deduction of Crown royalties and eliminating the resource allowance over a five year period. For True, the expected income tax charge was reduced by the impact of approximately 1.55% drop in tax rates, a change in valuation allowance, more than offset by a partnership deferral and flow-through share renouncements. Over the 2003 to 2007 period, the federal tax rate is to be reduced by seven percentage points, the resource allowance deduction is going to be phased out, to be replaced by a deduction for Crown royalties paid. For the year ended December 31, 2003, the provision for future income taxes was $4.35 million.

At the end of 2003, True had approximately $39.4 million of tax pools available for deduction against future earnings.

Summary of Tax Pools *($mm)*	***Estimated Balance at December 31, 2003***
Canadian exploration expense	1.0
Canadian development expense	10.2
Canadian oil and gas property expense	16.7
Undepreciated capital cost	10.3
Other	1.2
	39.4

LIQUIDITY AND CAPITAL RESOURCES

At the end of the year 2002, True had a net debt position of $19.9 million. By December 31, 2003, True's bank line draw was reduced to $11.6 million with a working capital deficit excluding bank debt of $2.9 million, or net debt of $14.5 million. The reduction in overall net indebtedness is due to cash flow from operations combined with the issuance of 8.5 million shares at $1.15 per share during the third quarter of 2003. The Company's net debt to historical cash flow ratio at the end of 2003 was 0.9 to 1.

Since December 31, 2002, the terms and conditions of the credit facility have been revised numerous times. The cost of borrowing was similarly reduced with the transition from prime plus one and a quarter percent to a price grid basis dependant on the Company's net debt to cash flow ratio on a quarter by quarter basis. Subsequent to the end of 2003, True's authorized line of credit was increased to $27.5 million, subject to an interim review on or before July 1, 2004 and an annual review by May 31, 2005.

On July 24, 2003 the Company issued 3.5 million flow-through common shares pursuant to a bought-deal private placement offering at a price of $1.15 per share for gross proceeds of $4.0 million. The Corporation is committed to renounce $4.025 million of Canadian Exploration Expense in 2003 to the subscribers of these shares. In 2003, True incurred $2.0 million of qualifying expenditures, and has until December 31, 2004 to incur the remainder. Based on the current forecasts of operations for 2004, the Company is confident this obligation will be met. On September 17, 2003 the Company issued 5.0 million common shares pursuant to a bought-deal private placement offering at a price of $1.15 per share for gross proceeds of $5.75 million. Proceeds from these offerings were used to fund the Company's ongoing exploration and development activities in its core areas, and for general corporate purposes.

At December 31, 2003 the Company had 54,044,420 common shares outstanding and 3,686,000 options outstanding at an average exercise price of $0.91 per share. As at March 26, 2004 total common shares issued and outstanding were 54,676,086 and 3,446,000 options were outstanding at an average price of $1.00 per share. The issuance of equity during 2004 was from the exercise of employee and director stock options.

FOURTH QUARTER

Cash flow from operations during the last quarter of 2003 was $4.3 million, an increase of 64% compared to $2.6 million in the fourth quarter of 2002. During the last quarter of 2003, True recorded a net loss of $0.8 million, compared to net earnings of $0.7 million in the prior year.

Sales volumes averaged 3,749 boe/d, up from the 3,303 boe/d reported during the third quarter of 2003. Sales of natural gas averaged 12.9 mmcf/d with the completion of a fourth Saskatchewan gas processing facility at Coleville South, additional compression at Smiley and as a result of successful drilling in the Coleville South, Coleville Driver, Dodsland / Druid, Donalda, and Goodwin areas. Heavy oil sales volumes averaged 1,329 bbls/d, an increase during the quarter of 308 bbls/d with the drilling of two horizontal heavy oil wells at Kerrobert.

In the last quarter of 2002, the Company recorded a 24 month payout for a natural gas property, making comparisons to gas sales volumes, average sales price, royalty rate and operating costs statistics not indicative of fundamental operations for this period. The payout reduced production volumes by 811 boe/d for the quarter (205 boe/d annualized).

True's natural gas price, before hedges, averaged $5.76/mcf, 1% greater than the Alberta spot price. During the fourth quarter, average Bow River heavy oil prices dropped 8% from the third quarter of 2003. True's average price declined 17% to $19.97/bbl, consistent with the changes in the Bow River heavy price and the cost of condensate used in blending.

Revenue was $10.3 million, up 78% from $5.8 million in the prior year, reflecting growth in production volumes reduced by lower overall commodity prices. A natural gas hedge increased sales by $80,669. The royalty burden remained consistent at 26% of gross sales. The Company recorded a negative adjustment of $38,000 for a pre-acquisition period ARTC audit. Operating costs for crude oil and NGLs averaged $6.42/bbl, down $2.33/bbl from the same period in 2002 reflecting a relatively normal winter and increased production volumes.

The combination of lower commodity prices and higher royalties partially offset by operating costs produced an average netback of $15.53/boe, only 58% of 2002 levels, primarily driven by a 24% decline in gas sales prices.

	Natural Gas ($/mcf)		Crude Oil and NGLs ($/bbl)	
Field Operating Netbacks	*2003*	*2002*	*2003*	*2002*
Sales	**5.76**	7.59	**23.08**	27.31
Hedge	**0.07**	-	**-**	-
Royalties	**(1.60)**	(0.79)	**(4.83)**	(4.34)
Production expense	**(1.18)**	(1.50)	**(6.42)**	(8.75)
Field operating netback	**3.05**	5.30	**11.83**	14.22

Net general and administrative costs were $0.8 million in the quarter, up from $0.5 million in 2002 with the inclusion of $0.2 million from the adoption of the Amended Stock Compensation regulations and severance costs of $0.3 million, which was capitalized.

Reduced borrowing levels and lower margins over prime in 2003 resulted in interest costs dropping to $0.1 million compared to $0.2 million in 2002.

The Company invested $7.5 million in oil and gas activities compared to $2.7 million in the same period of 2002, drilling 11 (6.8 net) wells, constructing a gas processing facility at Coleville South and adding additional compression at Smiley.

Depletion, depreciation and future site restoration was $2.9 million compared to $1.2 million for the same period of 2002. The more conservative reserve volumes from the adoption of NI 51-101 during the last quarter of 2003 triggered an increase in the Company's depletion and depreciation rate to $8.35/boe, compared to $7.06/boe in the prior quarter.

The provision for the Federal Large Corporation tax and the Saskatchewan Capital Tax was $0.3 million, growing with increased operations, especially in Saskatchewan. True recorded a provision for future income taxes of $2.0 million, bringing the future liability to $4.35 million by the end of the year. The estimated tax pool balance is after deducting the full amount of the July 2003 flow-through share issuance of $4.025 million, of which approximately $2.0 million of qualifying expenditures were incurred in the year. When the remaining qualifying expenditures are incurred, they will result in corresponding additions to the Company's estimated tax pool balance.

BUSINESS PROSPECTS AND 2004 OUTLOOK

True Energy is optimistic about its future prospects. The Company has been successful in growing its production and land base since its formation in September 2000 and is expected to continue with future growth through development of its core assets and new exploration on the Company's inventory of geological prospects. Currently, the Company's producing properties are located in west central Saskatchewan and west central Alberta. During 2004, the Company will continue to focus its exploration efforts in areas of multi-zone potential for natural gas and economically viable crude oil.

The Company anticipates that 2004 average production will be around 4,700 boe/d, approximately 65% weighted toward natural gas. Commodity prices will be volatile and principally impacted by weather, economic and political activity. The Company believes commodity prices for both crude oil and natural gas during 2004 will remain strong overall, while crude oil prices may strengthen and natural gas prices may soften somewhat. True anticipates the US $ / Cdn $ exchange rate to average 0.76 during 2004.

In 2004, operating costs for the winter months are expected to correlate directly to the severity of the winter weather. The duration of spring breakup will determine the late winter/ early spring cost levels. Assuming average temperatures and spring breakup, operating costs for 2004 are expected to be in the $7.00 to $7.50/boe range.

Subsequent to the end of 2003, True has drilled 23 (16.2 net) wells to date. During the first quarter of 2004, the Company completed the acquisition of assorted oil and gas interests in its west central Saskatchewan area. With this transaction, True acquired approximately 57,000 (31,026 net) acres, production and royalty interests located in True's Smiley, Dodsland, and Coleville Driver areas, and a 36.4% working interest in the True operated Smiley natural gas compression, dehydration and sweetening facility.

Currently, the Company anticipates spending $34 million during 2004 on oil and gas exploration and development activities within the core west central Saskatchewan and west central Alberta areas, of which $7.6 million is allocated to asset acquisitions.

The Company expects to be able to fund its capital expenditure program for 2004 using cash flow from operations and forecasted credit facilities. If cash flows are other than projected, capital expenditure levels will be adjusted to meet the targeted ratio. The Company's practices of continually monitoring spending opportunities in comparison to expected cash flow levels allow for adjustments to the capital program as required.

IMPACT OF NEW ACCOUNTING PRONOUNCEMENTS

In September 2002, the Canadian Institute of Chartered Accountants ("CICA") approved Section 3063, "Impairment of Long-Lived Assets" (S. 3063), establishing standards for the recognition, measurement and disclosure of the impairment of long-lived assets, and applies to long-lived assets held for use. An impairment loss is recognized when the carrying value exceeds its fair value and is not recoverable. This standard is effective for fiscal years beginning on or after April 1, 2003. Accounting Guideline 16, "Oil and Gas Accounting Full Cost" (AcG-16), issued in September 2003 includes this section in the application of the impairment test for oil and gas companies using the full cost method of accounting. The carrying value for oil and gas properties is limited to their fair value, which is equal to estimated future cash flows from proved and probable reserves, calculated using future price forecasts and costs discounted at a risk-free rate. The current ceiling test uses undiscounted cash flows determined using constant prices, reduced for general and administrative and financing costs. True will adopt AcG-16 effective January 1, 2004. The Company does not currently anticipate adoption of this standard will have a material adverse impact on its financial position or results of operations.

For fiscal years commencing on or after July 1, 2003, the CICA's new accounting pronouncement Accounting Guideline 13 "Hedging Relationships" (AcG-13) is in effect. This Guideline sets out certain conditions when hedge accounting may be applied; otherwise the fair values of derivative financial instruments are recorded as an asset or liability on the balance sheet. True does not currently have any hedges; hence the guideline has no current applicability. True currently cannot reasonable estimate the effect this policy would have.

For the fiscal year beginning on January 1, 2004, True will adopt the CICA's new section "Asset Retirement Obligations" (Section 3110), as required. This new accounting pronouncement requires accrued reclamation and abandonment obligations be recognized on the balance sheet by increasing oil and gas properties offset by a corresponding liability. The asset and liability are initially measured at fair value, being the discounted future value of the liability, and then capitalized as part of the cost of the asset and subsequently amortized over the life of the asset. The liability accretes until the retirement obligation is settled. Comparative numbers for 2003 and prior periods will be restated. The Company does not currently anticipate adoption of this standard will have a material adverse impact on its financial position or results of operations.

Effective March 31, 2004, True will be subject to new disclosure requirements as set out in National Instrument 51-102 ("NI 51-102"), requiring shorter reporting periods and enhanced disclosure for annual and interim financial statements, management's discussion and analysis, and the annual information form.

SENSITIVITY ANALYSIS

The table below shows sensitivities to cash flow as a result of product price and operational changes. This is based on average production volumes of 4,600 boe/d. These sensitivities are approximations only, and not necessarily valid under other significantly different production levels or product mixes. Hedging activities can significantly affect these sensitivities. Changes in any of these parameters will affect cash flow as shown in the table below:

Sensitivity Analysis	*Cash Flow From Operations ($000s)*	*Cash Flow Per Diluted Share ($)*
Change of US$1.00/bbl WTI	438	0.01
Change of US$0.10/mcf	642	0.01
Change of US$0.01 Canadian/US exchange rate	(548)	(0.01)
Change in prime of 1%	(200)	(0.00)

BUSINESS RISKS, UNCERTAINTIES AND FORWARD LOOKING STATEMENTS

This document contains statements about expected future events and/or financial result that are forward looking in nature and subject to substantial risks and uncertainties. The Company cautions the readers that actual performance will be affected by a number of factors, many of which are beyond its control, as many may respond to changes in economic and political circumstances throughout the world. These external factors beyond the Company's control may affect the marketability of oil and natural gas produced, industry conditions including changes in laws and regulations, changes in income tax regulations, increased competition, fluctuations in commodity prices, interest rates, and variations in the Canadian/United States dollar exchange rate.

True's production and exploration activities are concentrated in the Western Canada Sedimentary Basin, where activity is highly competitive and includes a variety of different sized companies ranging from smaller junior producers to the much larger integrated petroleum companies. True is subject to the various types of business risks and uncertainties including:

- *Finding and developing oil and natural gas reserves at economic costs;*
- *Production of oil and natural gas in commercial quantities; and*
- *Marketability of oil and natural gas produced.*

In order to reduce exploration risk, the Company employs highly qualified and motivated professional employees who have demonstrated the ability to generate quality proprietary geological and geophysical prospects. To maximize drilling success, True explores in areas that afford multi-zone prospect potential, targeting a range of low to moderate risk prospects with some exposure to select high-risk with high-reward opportunities.

The Company mitigates its risk related to producing hydrocarbons through the utilization of the most appropriate technology and information systems. In addition, True seeks to maintain operational control of the majority of its prospects.

Oil and gas exploration and production can involve environmental risks such as pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. In order to mitigate such risks, True conducts its operations at high standards and follows safety procedures intended to reduce the potential for personal injury to employees, contractors and the public at large. The Company maintains current insurance coverage for general and comprehensive liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect changing corporate requirements, as well as industry standards and government regulations. True may periodically use futures and options contracts to hedge its exposure against the potential adverse impact of commodity price volatility, as governed by formal policies approved by senior management subject to controls established by the Board of Directors.

CRITICAL ACCOUNTING ESTIMATES

In preparing financial statements in accordance with generally accepted accounting principles, management makes certain judgments and estimates. Changes in these judgments and estimates could have a material impact on the financial results and financial condition. The following discussion outlines accounting policies and practices that are critical to determining True's financial results.

Reserves are critical to several accounting estimates, affecting net income through depletion, site restoration and abandonment estimates and the ceiling test calculation. Estimating reserves is very complex, requiring many judgments based on available geological, geophysical, engineering and economic data. Estimated reserves are also utilized by True's bank in determining credit facilities. Changes in these judgments could have a material impact on the estimated reserves, and subsequently the Company's financial results and financial condition.

In following the liability method of accounting for income taxes, related assets and liabilities are recognized for the estimated tax consequences between amounts included in the financial statements and their tax base using substantively enacted future income tax rates. Timing of future revenue streams and future capital spending changes can affect the timing of any temporary differences, and accordingly affect the amount of the future income tax liability calculated at a point in time. These differences could materially impact earnings.

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favor, the Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceeding related to these and other matters or any amount which it may be required to pay by reason thereof would have a material adverse impact on its financial position or results of operations.

With the above risks and uncertainties associated with oil and gas operations and the evaluation of reserves, the reader is cautioned that future events and results may vary substantially from that which True currently foresees.

COMMITMENTS

In 2003, the Company entered into a large area farm-in arrangement in the Whitecourt, Alberta area committing to drill four wells prior to March 15, 2004. True completed the terms of this farm-in obligation during the first quarter of 2004.

The Company has committed to drill one well in Alberta pursuant to a farm-in agreement with another oil and gas company during 2004.

True has no off-balance sheet arrangements or variable interest entities. The Company is committed to various office leases over the next five years as follows.

Year	Gross Amount	Expected Recoveries	Net Amount
2004	$ 654,789	$ 177,837	$ 476,952
2005	567,404	118,290	449,114
2006	518,153	59,145	459,008
2007	490,388	-	490,388
2008	286,060	-	286,060
	$ 2,516,794	$ 355,272	$ 2,161,522

SUMMARY OF QUARTERLY INFORMATION

The following table provides a summary by quarter for 2003 and 2002:

($000s, except as indicated)

2003 Quarter Ended	*March 31*	*June 30*	*September 30*	*December 31*
Revenue[1]	9,916	7,595	9,731	10,318
Cash flow from operations	4,374	2,489	4,637	4,308
Per basic share *($)*	0.10	0.06	0.10	0.08
Per diluted share *($)*	0.10	0.05	0.09	0.08
Net earnings (loss)	1,538	1,207	2,366	(782)
Per basic share *($)*	0.03	0.03	0.05	(0.01)
Per diluted share *($)*	0.03	0.03	0.05	(0.01)
Capital expenditures, net	2,613	4,985	4,913	7,529
Production *(boe/d)*	2,569	2,376	3,303	3,749

[1] *Before deduction of royalties.*

2002 Quarter Ended				
Revenue[1]	3,818	4,319	5,030	5,807
Cash flow from operations	514	1,260	1,505	2,633
Per basic share *($)*	0.02	0.04	0.04	0.06
Per diluted share *($)*	0.02	0.04	0.04	0.06
Net earnings (loss)	(744)	299	(32)	699
Per basic share *($)*	(0.03)	0.01	0.00	0.02
Per diluted share *($)*	(0.03)	0.01	0.00	0.02
Capital expenditures, net	1,154	(3,296)	18,277	2,667
Production *(boe/d)*	2,107	2,001	2,253	1,808

[1] *Before deduction of royalties.*

SELECTED ANNUAL INFORMATION

($000s, except as indicated)

Years Ended December 31,	*2003*	*2002*	*2001*
Revenue[1]	**37,560**	18,974	18,103
Cash flow from operations	**15,808**	5,912	4,159
Per basic share *($)*	**0.33**	0.16	0.21
Per diluted share *($)*	**0.32**	0.16	0.21
Net earnings (loss)	**4,329**	222	(19,300)
Per basic share *($)*	**0.09**	0.01	(0.99)
Per diluted share *($)*	**0.09**	0.01	(0.99)
Capital expenditures, net	**20,040**	18,802	37,804
Total assets	**63,060**	49,090	30,564
Total net debt - current	**14,461**	19,893	17,243
Long term financial liabilities			
Capital taxes payable	**836**	686	-
Future income taxes	**4,350**	-	-
Future site restoration and abandonment costs	**1,222**	830	427
Production *(boe/d)*	**3,003**	2,042	1,880

[1] *Before deduction of royalties.*

Management's Responsibilities for Financial Statements

The management of True Energy Inc. is responsible for the preparation and integrity of the accompanying consolidated financial statements and all other information contained in this annual report. The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada and include amounts that are based on management's informed judgments and estimates where necessary.

The Company maintains internal accounting control systems which are adequate to provide reasonable assurance that assets are safeguarded, transactions are executed in accordance with management's authorization and accounting records are reliable as a basis for the preparation of the consolidated financial statements.

The Board of Directors, through its Audit Committee, monitors management's financial and accounting policies and practices and the preparation of these financial statements. The Audit Committee meets periodically with the external auditors and management to review the work of each and the propriety of the discharge of their responsibilities.

Specifically, the Audit Committee reviews with management and the external auditors the financial statements and annual report of the Company prior to submission to the Board of Directors for final approval. The external auditors have full and free access to the Audit Committee to discuss auditing and financial reporting matters. The Shareholders have appointed KPMG LLP as the external auditors of the Company, and, in that capacity, they have examined the financial statements for the period ended December 31, 2003.

Paul R. Baay
President and CEO
March 26, 2004

Joan E. Dunne
Vice President, Finance and CFO

Auditors' Report to the Shareholders

We have audited the consolidated balance sheets of True Energy Inc. as at December 31, 2003 and 2002 and the statements of operations and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada
March 10, 2004

Consolidated Balance Sheets

For the years ended December 31,

		2003	2002
ASSETS			
Current assets			
Accounts receivable		**$ 9,754,654**	$ 7,699,237
Deposits and prepaids		**704,380**	853,208
		10,459,034	8,552,445
Property, plant and equipment	*Note 4*	**52,601,113**	40,537,151
		$ 63,060,147	$ 49,089,596
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities		**$ 13,336,706**	$ 11,249,520
Bank debt	*Note 5*	**11,582,860**	17,195,471
		24,919,566	28,444,991
Capital taxes payable		**835,878**	686,430
Future site restoration and abandonment costs		**1,222,474**	830,474
Future income taxes	*Note 9*	**4,350,000**	-
Shareholders' equity			
Share capital	*Note 7*	**46,723,901**	38,448,124
Deficit		**(14,991,672)**	(19,320,423)
		31,732,229	19,127,701
		$ 63,060,147	$ 49,089,596
Commitments	*Note 12*		

See accompanying notes to the consolidated financial statements.

On behalf of the Board of Directors,

Kenneth P. Acheson
Director
Chairman, Audit Committee

W. C. (Mickey) Dunn
Director
Chairman of the Board

Consolidated Statements of Operations and Deficit

For the years ended December 31,

		2003	2002
REVENUE			
Petroleum and natural gas sales		**$ 37,560,432**	$ 18,974,327
Royalties, net of Alberta royalty tax credit		**9,516,983**	4,464,490
		28,043,449	14,509,837
EXPENSES			
Production		**8,150,955**	5,119,012
General and administrative		**2,710,131**	2,128,488
Interest on debt		**773,454**	780,533
Depletion, depreciation and site restoration		**8,367,913**	5,180,268
		20,002,453	13,208,301
EARNINGS BEFORE TAXES		**8,040,996**	1,301,536
TAXES	*Note 9*		
Current income tax recoveries		**(186,611)**	(71,340)
Capital taxes		**784,448**	1,151,213
Future income tax		**3,114,408**	-
		3,712,245	1,079,873
NET EARNINGS		**4,328,751**	221,663
Deficit, beginning of period		**(19,320,423)**	(19,542,086)
Deficit, end of period		**$ (14,991,672)**	$ (19,320,423)
Net earnings per share	*Note 10*		
Basic		**$ 0.09**	$ 0.01
Diluted		**$ 0.09**	$ 0.01

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

For the years ended December 31,

		2003	2002
Cash provided by (used in):			
OPERATIONS			
Net earnings		**$ 4,328,751**	$ 221,663
Charges not involving cash:			
Depletion, depreciation and site restoration		**8,367,913**	5,180,268
Future income tax		**3,114,408**	-
Capital tax (recovery)		**(3,546)**	686,430
Prepaid contract revenue	*Note 6*	**-**	(176,700)
Cash flow from operations		**15,807,526**	5,911,661
Change in non-cash working capital		**(3,358,812)**	(2,103,736)
		12,448,714	3,807,925
FINANCING			
Issuance of common shares	*Note 7*	**10,081,567**	3,050,299
Share issue costs	*Note 7*	**(774,727)**	(406,065)
Stock option costs	*Notes 7 & 8*	**204,530**	-
Repayment of debt acquired on acquisition of Gresham Resources Inc.	*Note 3*	**-**	(9,077,736)
Increase (decrease) in bank debt		**(5,612,611)**	4,053,538
		3,898,759	(2,379,964)
INVESTING			
Additions to capital assets		**(19,408,319)**	(9,683,821)
Acquisition of capital assets		**(631,556)**	(911,103)
Proceeds on sale of capital assets		**-**	6,377,618
		(20,039,875)	(4,217,306)
Change in non-cash working capital		**3,692,402**	2,789,345
		(16,347,473)	(1,427,961)
Change in cash		**-**	-
Cash, beginning of period		**-**	-
Cash, end of period		**$ -**	$ -

See accompanying notes to the consolidated financial statements.

1. SIGNIFICANT ACCOUNTING POLICIES:

The consolidated financial statements of the Company have been prepared by management in accordance with generally accepted accounting principles in Canada. The preparation of consolidated financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. The amounts recorded for depletion and depreciation, the provision for future site restoration, ceiling test factors such as proved reserves production rates, oil and natural gas prices and future costs are estimated. Actual results could differ from those estimates. The consolidated financial statements have, in management's opinion, been properly prepared using careful judgment and reasonable limits of materiality and within the framework of the significant policies summarized below:

a) Principles of consolidation:
The consolidated financial statements include the accounts of the Company and its subsidiaries. Any reference to "the Company" throughout these consolidated financial statements refers to the Company and its subsidiaries. All inter-entity transactions have been eliminated.

b) Petroleum and natural gas properties:
The Company follows the full cost method of accounting for petroleum and natural gas operations whereby all costs related to the exploration and the development of petroleum and natural gas reserves are capitalized. These costs include land acquisition costs, geological and geophysical expenses, the costs of drilling both productive and non-productive wells and directly related overhead. Proceeds from the disposal of properties are deducted from the full cost pool without recognition of a gain or loss unless such a sale would significantly alter the rate of depletion and depreciation.

c) Depletion and depreciation:
Depletion of petroleum and natural gas properties is provided using the unit-of-production method based on production volumes before royalties in relation to total estimated proved reserves as determined by independent engineers and calculated in accordance with National Instrument 51-101. Natural gas reserves and production are converted at the energy equivalent of six thousand cubic feet to one barrel of oil.

Calculations for depletion and depreciation of production equipment are based on total capitalized costs plus estimated future development costs of proved undeveloped reserves. The costs of acquiring and evaluating unproved properties are excluded from depletion calculations. These properties are assessed periodically to ascertain whether impairment has occurred. When the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion.

The Company applies a ceiling test to capitalized costs to ensure that such costs do not exceed the aggregate of the costs of unproved properties plus future net revenues from production of proved reserves at year end product prices less future administrative, financing, site restoration and income tax expenses.

d) Joint interests:
Substantially all of the Company's exploration and development activities are conducted jointly with others and, accordingly, the financial statements reflect only the Company's proportionate interest in such activities.

e) Future site restoration and abandonment costs:
Future site restoration and abandonment costs are based on management's estimates and amortized using the unit-of-production method over the remaining proved reserves. The provision is included in depletion, depreciation and site restoration in the statement of operations.

f) Prepaid contracts:
Advance payments received under prepaid contracts for oil and gas which is not delivered are deferred and are recognized as revenue when deliveries are made. Revenue is recognized on a straight line basis by dividing the advance payment by the total contracted volumes.

g) Flow-through common shares:
Resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share issues are renounced to investors in accordance with income tax legislation. The estimated tax benefits transferred to shareholders are recorded as future income taxes and reduce share capital.

h) Derivative financial instruments:
The Company uses derivative financial instruments from time to time to hedge its exposure to commodity price and foreign exchange fluctuations. The Company does not enter into derivative financial instruments for trading or speculative purposes.

The derivative financial instruments are initiated within the guidelines of the Company's risk management policy. This includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, as the term and notional amount do not exceed the Company's firm commitment or forecasted transaction, and the underlying basis of the instrument, such as commodity price or foreign exchange rate, matches the Company's exposure.

The Company enters into hedges of its exposure to petroleum and natural gas commodity prices by entering into crude oil and natural gas swap contracts, options or collars, when it is deemed appropriate. These derivative contracts, accounted for as hedges, are not recognized on the balance sheet. Realized gains and losses on these contracts are recognized in petroleum and natural gas revenue and cash flows in the same period in which the revenues associated with the hedged transaction are recognized. Premiums paid or received are deferred and amortized to earnings over the term of the contract.

i) Stock-based compensation plan:
The Company has one stock-based compensation plan, which is described in note 7 (c). Effective January 1, 2003, compensation expense is recognized for these plans when stock options are issued to employees and extending through the vesting periods of the options. Any consideration paid by employees is credited to share capital.

j) Revenue recognition:
Revenues from the sale of petroleum and natural gas are recorded when title passes to an external party.

k) Income taxes:
Income taxes are recorded using the liability method of tax allocation. Future income tax assets and liabilities are determined based on "temporary differences" and are measured using the current, or substantively enacted, tax rates and laws expected to apply when these differences reverse. A valuation allowance is recorded against any future income tax asset if it is more likely than not that the asset will not be realized.

l) Cash and cash equivalents:
Cash and cash equivalents include bank balances and highly liquid temporary money market instruments with original maturities of three months or less.

2. CHANGE IN ACCOUNTING POLICY:

Stock-Based Compensation Plan

In September 2003, the CICA amended Section 3870 "Stock-based compensation and other stock-based payments" to be effective for fiscal years beginning on or after January 1, 2004 with earlier adoption encouraged. In the fourth quarter of 2003, the Company adopted the amended standard which requires the use of the fair value method for valuing stock option grants. Under this method, compensation cost, attributable to share options granted to employees or directors is measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. Upon the exercise of the stock options, consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital. Pursuant to the transition rules, the expense recognized applies to stock options granted on or after January 1, 2003. The impact of the adoption of this amended standard is disclosed in note 8.

3. ACQUISITIONS / DISPOSITIONS:

Effective October 1, 2003, the Company entered into an agreement with an arm's length third party to purchase certain petroleum and natural gas assets located in central Alberta, specifically in the Goodwin, Greencourt, and Corbett areas (the "Acquisition"). Closing of the acquisition occurred on December 4, 2003 and the Company has accounted for this acquisition as a purchase on this date. The purchase price of $477,412 was fully allocated to petroleum and natural gas properties and has an equivalent tax basis.

On April 26, 2002 the Company sold certain non-strategic assets in the Milton/Hoosier areas to an arm's length third party for net proceeds of $5.9 million. The proceeds from this disposition were fully allocated to petroleum and natural gas properties and have an equivalent tax basis.

On July 31, 2002, the Company acquired all of the issued and outstanding shares of Gresham Resources Inc. pursuant to the plan of arrangement on the basis of 1.4 common shares of the Company for each outstanding share of Gresham. After giving effect to this transaction, the Company had 45,117,756 common shares issued and outstanding. The acquisition was accounted for using the purchase method and was effective July 31, 2002 being the date the majority of Gresham shares were taken up and exchanged for True shares.

The net assets acquired and consideration given were:

Net assets acquired:	
Property, plant and equipment	$ 14,762,668
Working capital	1,912,955
Future site restoration and abandonment	(100,890)
Debt	(9,077,736)
	$ 7,496,997
Consideration:	
Issued 12,232,654 shares of True Energy valued at $0.60 per share	$ 7,319,313
Acquisition costs	177,684
	$ 7,496,997

On October 17, 2002, the Company sold its assets in the north Dodsland Viking Voluntary Unit to an arm's length third party for $424,000. The proceeds from this disposition were fully allocated to petroleum and natural gas properties and have an equivalent tax basis.

4. PROPERTY, PLANT AND EQUIPMENT:

December 31, 2003	*Cost*	*Accumulated Depletion and Depreciation*	*Net Book Value*
Petroleum and natural gas properties	$ 112,499,021	$ 60,408,569	$ 52,090,452
Office furniture and equipment	902,817	392,156	510,661
	$ 113,401,838	$ 60,800,725	$ 52,601,113
December 31, 2002			
Petroleum and natural gas properties	$ 92,616,603	$ 52,530,569	$ 40,086,034
Office furniture and equipment	745,360	294,243	451,117
	$ 93,361,963	$ 52,824,812	$ 40,537,151

At December 31, 2003, the estimated future site restoration costs to be accrued over the remaining proved reserves are $1,886,000 (2002 - $2,022,000) of which $392,000 has been recorded as additional depletion and depreciation during 2003 (2002 - $303,000).

Unproved properties with a cost of approximately $11,294,000 (2002 - $9,195,000) included in property, plant and equipment have not been subject to depletion.

At December 31, 2003, the Company performed the ceiling test, using year end prices, and no write-down of the carrying value of the assets is required.

5. BANK DEBT:

The Company has a demand revolving credit facility with an authorized borrowing amount of $20,000,000 with a Canadian chartered bank. Interest is payable at the lenders' prime rate plus an applicable margin, as outlined in the lending agreement, based on the debt to cash flow ratio. Security is provided by a general assignment of book debts of the Company, a $10,000,000 floating charge debenture over all assets of the Company, a fixed charge over certain producing petroleum and natural gas reserves at Smiley and first floating charge supplemental debentures of $80,000,000. A standby fee is charged on one half of one percent on the undrawn portion of the credit facility. The availability under the facility is subject to an interim review by January 31, 2004, and an annual review by May 31, 2004.

6. PREPAID GAS CONTRACT:

The Company entered into a prepaid contract for future delivery of natural gas commencing November 1, 1998. The Company received $1,387,000 on November 1, 1998 for 1,000 gigajoules of natural gas per day at $1.90 per gigajoule at the wellhead for a period of two years.

On July 18, 2000, an amending agreement was signed with the consumer which stated that the Company did not have to deliver any gas for the seven months from June 1 to December 31, 2000. The completion of the 458,000 gigajoules of pre-purchase gas delivery restarted at the 1,000 gigajoules per day rate on January 1, 2001. The Company satisfied the remaining obligations under the contract during 2002.

7. CAPITAL STOCK AND CONTRIBUTED SURPLUS:

a) Authorized:
Unlimited number of voting common shares
Unlimited number of non-voting first preferred shares

b) Issued:

Common Shares	*Number of Shares*	*Amount*
Balance, December 31, 2001	28,775,102	$ 28,484,577
Options exercised	26,665	16,299
Issued through private placement	4,100,000	3,034,000
Issued on acquisition of Gresham Resources Inc.	12,232,654	7,319,313
Share issue costs		(406,065)
Balance, December 31, 2002	45,134,421	38,448,124
Issued on exercise of stock options	409,999	306,567
Issued for cash on private placement	5,000,000	5,750,000
Flow-through shares issued for cash on private placement	3,500,000	4,025,000
Contributed surplus	-	204,530
Share issue costs, net of future income taxes of $484,290	-	(290,438)
Tax effect of flow-through shares	-	(1,719,882)
Balance, December 31, 2003	54,044,420	$ 46,723,901

The Company has commitments to incur $2,038,231 of Canadian Exploration Expense deductions in 2004 to satisfy flow-through agreements.

c) Stock options:
On August 31, 2000, the Board of Directors approved a stock option plan (the "Plan") for directors, officers, employees and consultants of the Company up to a maximum amount as approved by the shareholders (4,825,000 at December 31, 2003 and 3,050,000 at December 31, 2002). The exercise price shall not be lower than the closing sale price for board lots of common shares on the trading day immediately prior to the day on which the options are granted, and an option's maximum term is five years. The vesting period is determined by the Board and averages three years.

The following table summarizes information about stock options outstanding at December 31, 2003:

Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercisable Price
$0.57 to $0.70	837,500	3.3	$0.64	425,000	$0.64
$0.73 to $0.79	1,315,000	3.4	0.75	787,500	0.75
$0.85 to $1.00	500,000	3.1	0.92	266,666	0.90
$1.15 to $1.24	359,000	4.2	1.22	-	-
$1.30 to $1.70	674,500	4.5	1.36	-	-
$0.57 to $1.70	3,686,000	3.6	$0.91	1,479,166	$0.75

The following table summarizes the changes in stock options outstanding:

	Options	Weighted Average Exercise Price
Outstanding at December 31, 2001	2,022,500	$0.91
Cancelled	(1,669,169)	0.86
Granted	2,202,500	0.70
Exercised	(26,665)	0.61
Outstanding at December 31, 2002	2,529,166	$0.77
Cancelled	(186,667)	0.73
Granted	1,753,500	1.05
Exercised	(409,999)	0.75
Outstanding at December 31, 2003	3,686,000	$0.91

8. STOCK-BASED COMPENSATION:

At December 31, 2003, the Company has one stock-based compensation plan, which is described in Note 7(c). In the fourth quarter of 2003, the Company prospectively adopted the amendments to CICA Handbook Section 3870 "Stock-based compensation and other stock-based payments" pursuant to the transitional provisions contained therein. In accordance with the transition rules, the expense recognized applies to stock options granted in 2003. During the twelve months ended December 31, 2003, the Company granted 1,753,500 (2002 - 2,202,500) stock options to employees, consultants and directors. As a result of adopting this amended standard, net income for the year ended December 31 2003, decreased by $204,530 and contributed surplus increased by $204,530.

For stock options granted in 2002 and prior years, the Company elected to continue accounting for the related compensation expense on the intrinsic value at the grant date. Accordingly, net income for 2002 and subsequent years remains unchanged with respect to stock options granted in 2002.

The Company continues to disclose the pro forma earnings impact of stock options granted in 2002. If the fair value method had been used for options granted in 2002, the Company's net earnings and net earnings per share for the years ended December 31, 2003 and 2002 would approximate the following pro forma amounts:

	2003	2002
Net earnings (loss):		
As reported	**$ 4,328,751**	$ 221,663
Pro forma	**$ 4,127,773**	$ (518,688)
Net earnings per share:		
As reported	**$ 0.09**	$ 0.01
Pro forma	**$ 0.09**	$ (0.01)
Diluted:		
As reported	**$ 0.09**	$ 0.01
Pro forma	**$ 0.08**	$ (0.01)

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions and resulting values for grants as follows:

	2003	2002
Assumptions:		
Risk free interest rate *(%)*	**5.66**	5.73
Expected life *(years)*	**5.0**	5.0
Expected volatility *(%)*	**85**	105
Results:		
Weighted average fair value of options granted *($)*	**0.52**	0.56

9. INCOME TAXES:

The provision for income taxes differs from the expected amount calculated by applying the combined federal and provincial corporate income tax rate (2003 - 42.75%, 2002 - 44.30%) to earnings before income taxes. This difference results from the following items:

	2003	2002
Expected income tax expense	**$ 3,437,616**	$ 576,559
Crown royalties and charges	**1,767,302**	1,273,618
Resource allowance	**(1,654,500)**	(1,015,129)
Change in valuation allowance	**(916,434)**	(17,711)
Change in enacted tax rates	**117,884**	1,784
Other	**362,540**	(819,121)
Future income tax expense	**3,114,408**	-
Current income tax recoveries	**(186,611)**	(71,340)
Capital tax expense	**784,448**	1,151,213
Total tax expense	**$ 3,712,245**	$ 1,079,873

The components of the net future income tax liability at December 31 are as follows:

	2003	2002
Future income tax liabilities:		
Petroleum and natural gas properties	$ (2,004,192)	$ -
Partnership deferral	(5,374,987)	-
Future income tax assets:		
Petroleum and natural gas properties	261,795	95,564
Future site restoration	440,420	275,915
Share issue costs	757,500	544,955
Non-capital losses	1,160,946	
Attributed Canadian Royalty Income	386,658	
Other	21,860	
	(4,350,000)	916,434
Valuation allowance	-	(916,434)
Net future income tax liability	$ (4,350,000)	$ -

During 2003, a current income tax recovery of $186,611 was recorded to reflect overestimated income taxes owing by Gresham Resources Inc. and Marengo Exploration Ltd.

During 2002, a current income tax recovery of $71,340 was recorded to reflect overestimated income taxes owing by Marengo Exploration Ltd. and True Energy Inc.

Included in capital tax expense of $784,448 are capital taxes of $835,878 that will become payable in 2004.

10. PER SHARE AMOUNTS:

Basic per share amounts are calculated using the weighted average number of shares outstanding during the year.

The Company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. Under the treasury stock method, only "in the money" dilutive instruments impact the diluted calculations in computing diluted earnings per share.

In computing diluted earnings and cash flow from operations per share, 950,147 (2002 - 55,113) shares were added to the 48,335,571 (2002 - 36,505,356) weighted average number of common shares outstanding during the year for the dilutive effect of stock options. A total of 1,021,500 (2002 - 1,960,000) options were excluded from the calculation as they were not dilutive.

11. SUPPLEMENTAL CASH FLOW INFORMATION:

	2003	2002
Cash paid:		
Interest	$ 773,454	$ 780,533
Taxes (net of refunds)	$ (152,706)	$ 224,701
Non-cash investing and financing activities:		
Issue of common shares on acquisition of Gresham	-	$ 7,319,313
Net assets acquired on acquisitions	-	$ 7,496,997

12. COMMITMENTS:

The Company is committed to payments under operating leases for office space as follows:

Year	Gross Amount	Expected Recoveries	Net Amount
2004	$ 654,789	$ 177,837	$ 476,952
2005	567,404	118,290	449,114
2006	518,153	59,145	459,008
2007	490,388	-	490,388
2008	286,060	-	286,060
	$ 2,516,794	$ 355,272	$ 2,161,522

13. FINANCIAL INSTRUMENTS COMMODITY RISK:

a) Credit risk:
A substantial portion of the Company's accounts receivable are with customers and joint venture partners in the petroleum and natural gas industry and are subject to normal industry credit risks. The Company sells substantially all of its production to three primary purchasers under normal industry sale and payment terms. Purchasers of the Company's natural gas, crude oil and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment.

b) Fair value of financial instruments:
The carrying amounts of financial instruments included in the balance sheet, other than long-term debt, approximate their fair value due to their short-term maturity. The long-term carrying value approximates fair value due to the cost of borrowing being at a floating rate.

c) Commodity risk:
The Company seeks to reduce its exposure to commodity price risk in its business through the use of physical product arrangements, futures, and options.

On January 30, 2003, the Company entered into a natural gas commodity price swap for 3,000 gigajoules per day for the period April 1, 2003 to October 31, 2003. The contract establishes that the Company would pay the counter party the differential for any month when the AECO "C" price was established at more than CDN $6.08 per gigajoule and that the counter party would pay the Company the differential when the AECO "C" price was established at less than CDN $6.08 per gigajoule. For the year ended December 31, 2003, the Company recorded a reduction to gas sales of $57,861 for this transaction.

The Company had entered into a fixed price sales contract to deliver heavy oil Lloydblend (LLK) at a price of $30.18 per barrel on 200 barrels per day for the period from May 1, 2002 to December 31, 2002. Effective October 1, 2002, the fixed price sales contract was modified in respect of the committed volumes to 100 barrels per day from October 1, 2002 to December 31, 2002.

In addition, the Company had entered into a fixed price sales contract to deliver heavy oil Lloydblend (LLK) at a price of $26.74 per barrel on 100 barrels per day for the period from May 1, 2002 to April 30, 2003. Effective October 1, 2002, the fixed price sales contract was modified in respect of the committed volumes to 50 barrels per day from October 1, 2002 to April 30, 2003.

The Company had entered into another fixed price sales contract to deliver heavy oil Lloydblend (LLK) at a price of $27.87 per barrel on 200 barrels per day for the period January 1, 2003 to June 30, 2003.

During March 2002, the Company entered into a natural gas contract for 3,000 gigajoules per day for the period April 1, 2002 to October 31, 2002. The contract established a floor price of CDN $4.00 per gigajoule and a ceiling price of CDN $5.00 per gigajoule at the AECO-C Hub. The total gain included in 2002 revenue relating to this hedging transaction was $254,701.

14. SUBSEQUENT EVENTS:

a) During the third quarter of 2003, the Company committed to drill four wells pursuant to a farm-in agreement with an oil and gas company in the Whitecourt, Alberta area by March 15, 2004. At December 31, 2003, the Company has drilled two of the four wells and has drilled the remaining two during the first quarter of 2004.

The Company has committed to drill one well in Alberta pursuant to a farm-in agreement with another oil and gas company during 2004.

b) Effective January 1, 2004, the Company entered into an agreement with an arm's length third party to purchase certain petroleum and natural gas assets located in the Company's west central Saskatchewan core area. Closing of the acquisition occurred on March 1, 2004 and the Company will account for this acquisition as a purchase on this date.

Abbreviations and Glossary

AECO	*a storage and pricing hub for Canadian natural gas markets*
/d	*per day*
boe	*barrels of oil equivalent (6 mcf of natural gas = 1 barrel of oil equivalent)*
bbls	*barrels*
established reserves	*proved reserves plus one half probable reserves*
mboe	*thousand barrels of oil equivalent*
mcf	*thousand cubic feet*
mmboe	*millions barrels of oil equivalent*
mmcf	*million cubic feet*
NGLs	*natural gas liquids*
WTI	*West Texas Intermediate, a benchmark crude oil used for pricing comparison*

Corporate Information

BOARD OF DIRECTORS

W.C. (Mickey) Dunn, *Chairman* (1) (3) (4)
Independent Businessman
Edmonton, Alberta

Kenneth P. Acheson (1) (4)
President, Kennington Properties Inc.
Calgary, Alberta

Paul R. Baay
President and CEO, True Energy Inc.
Calgary, Alberta

John H. Cuthbertson, *Corporate Secretary* (4)
Partner, Burnet, Duckworth & Palmer LLP
Calgary, Alberta

James R. Glass (2) (3)
Independent Businessman
Parksville, British Columbia

Robert G. Rowley, Q.C. (1) (2)
Independent Businessman
Calgary, Alberta

Kim M. Ward (2) (3)
Independent Businessman
Toronto, Ontario

OFFICERS

Paul R. Baay
President and CEO

Clinton T. Broughton
Vice President

Joan E. Dunne
Vice President, Finance and CFO

Bradley D. Maynes
Vice President, Exploration

Committees of the Board of Directors
(1) Audit Committee member
(2) Reserves Committee member
(3) Compensation Committee member
(4) Corporate Governance Committee member

EXCHANGE LISTING

The Toronto Stock Exchange, TUI

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

AUDITORS

KPMG LLP

BANKERS

National Bank of Canada

EVALUATION ENGINEERS

Gilbert Laustsen Jung Associates Ltd.

REGISTRAR AND TRANSFER AGENT

Computershare Trust Company of Canada

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